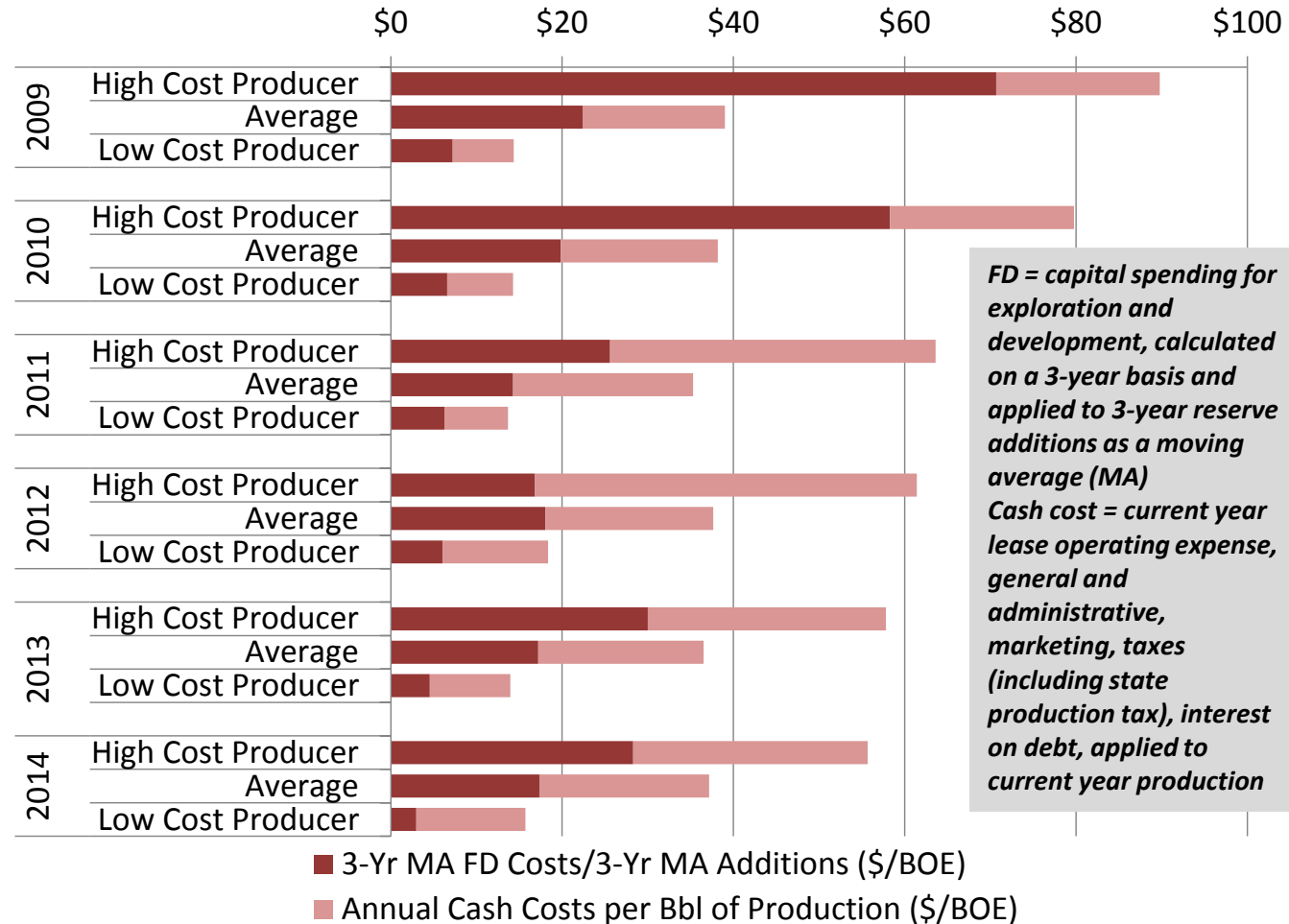


# Upstream Matters! Part Deux

*We add 2014 reporting data and affirm key considerations going forward*

***Our sample represents the top tier of U.S. producers including leading shale players.***

- We have **\*restated work** from earlier research for changes to our sample and methodology
- The 15 publicly traded companies we use comprise **68% of Top 40** gas producers (NGSA.org) and **33% of U.S.** marketed natural gas production
- In this snapshot including **2014** reporting we state results mainly in barrel of oil equivalent terms
- Overall, while FD capex has dropped, largely a result of increased volumes, **cash costs remain substantial and stubborn.**



*FD = capital spending for exploration and development, calculated on a 3-year basis and applied to 3-year reserve additions as a moving average (MA)  
Cash cost = current year lease operating expense, general and administrative, marketing, taxes (including state production tax), interest on debt, applied to current year production*

***The cheapest producers are also the “gassiest” – smaller companies that, for the most part, did not move out of gas and into liquids because of cost and capital constraints.***

\* <http://www.beg.utexas.edu/energyecon/thinkcorner/Think%20Corner%20-%20Producers.pdf>

# How much spending?

## With what results??

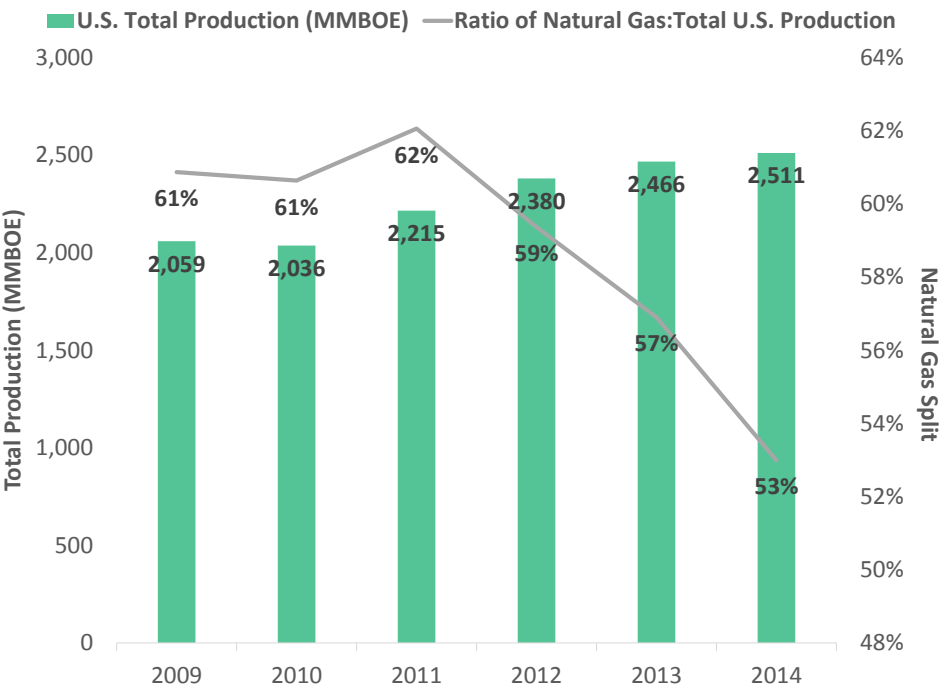
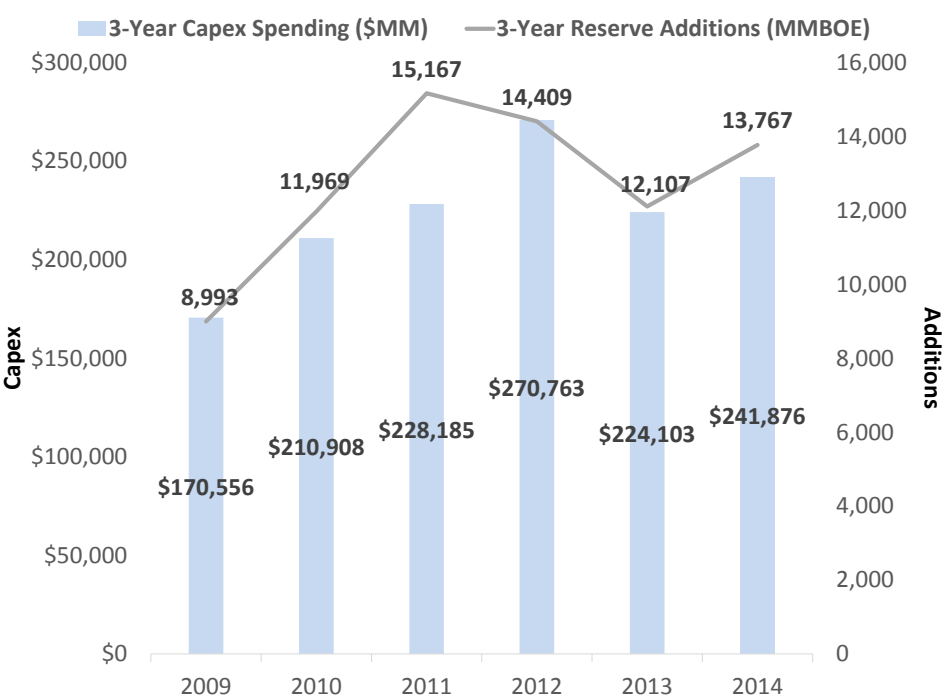
*In the complex commodity markets of today, U.S. producer performance and cost is increasingly relied upon as a guide to possible floor prices and longer term price trends.*

We use 3 year rolling total FD spending against 3 year reserve additions to reach FD/BOE.

- The capex requirements to high grade upstream, especially shale, portfolios has been considerable, **exceeding \$270 billion** by 2012.
- **Substantial write downs and impairments were taken in 2012 (slide 3)** as a result of the steep fall in gas prices. Reductions in capex are discernible when 2013 data are added **but rose again in 2014.**

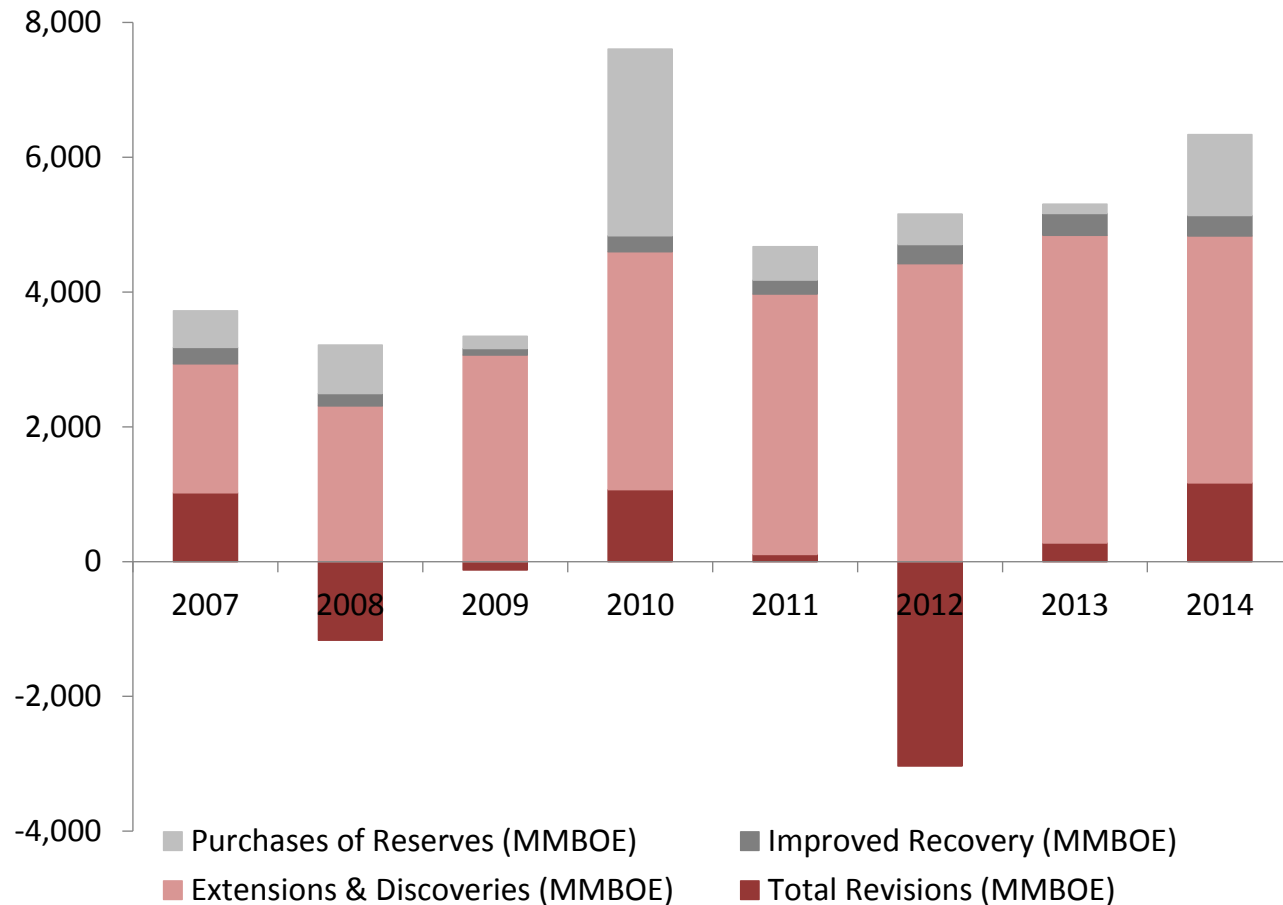
We use cash cost against current production for cash cost/BOE.

- Companies have grown production on a BOE basis by **about 22 percent** since 2010.
- **Natural gas remains the dominant proportion** of production streams **but 2014 showed a marked shift.** This pattern holds when we compare our results to other research.
- **9 of the 15 companies in our sample are predominantly gas producers** (50 to nearly 100 percent of production) including 6 that are among the shale “specialists” and 1 integrated major.



# Bonus: Sources of Additions

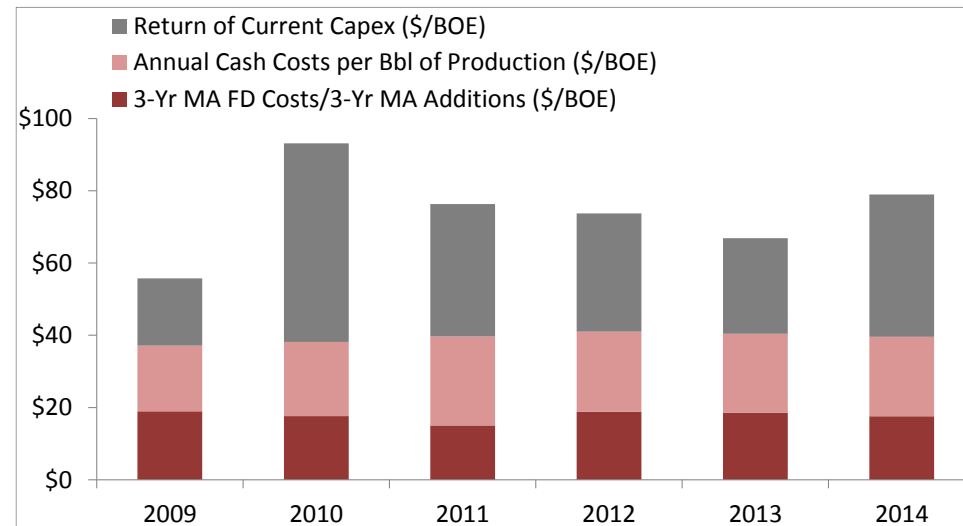
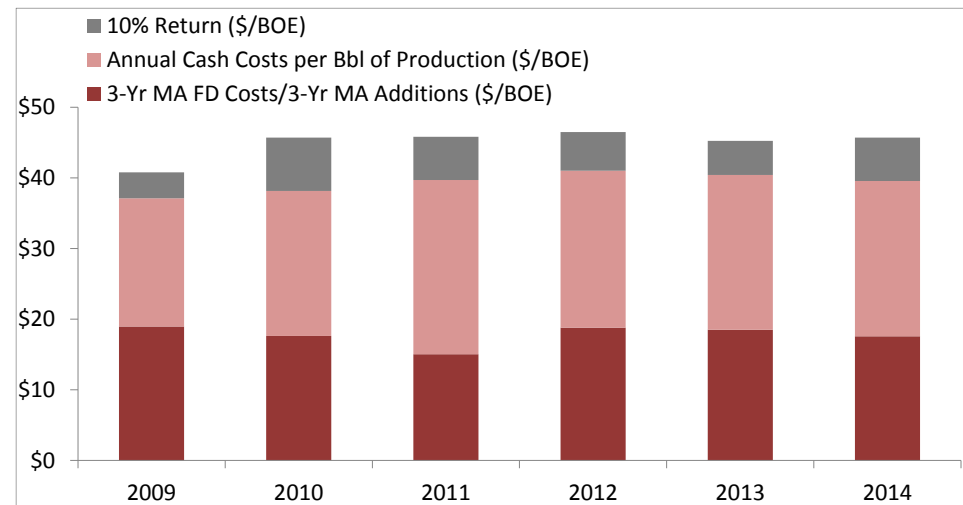
*Most booked additions come from drilling out acreage as opposed to improved recovery.*



# Computing Returns

***U.S. producers have demonstrated success in key shale plays but it is not an easy business.***

- In **BOE terms**, on average and as of **2014**, the **full cycle cost for our sample is close to \$50 per BOE** with a 10 percent return assumed.
- However, a 10 percent return does not provide sufficient recovery of capital spent in a current year.
- Alternatively, we use a return equal to capex spent that year against current production.
- **With the alternative criteria imposed, the average full cycle cost for 2014 was about \$80 per BOE.** We believe this suggests an oil price signal of **at least \$80** is needed to sustain activity for our sample and the industry.
- We note that many producers realize considerably less than the traded domestic oil prices. Condensate, the main component of many production streams, typically sells \$20-25 below West Texas Intermediate.
- Overall, the industry remains predominantly cash flow negative. Companies have had to spend capital well above cash flow from operations to replace production and improve leasehold positions. **With lower oil prices companies are working to adjust capital spending to fall within cash flows.**

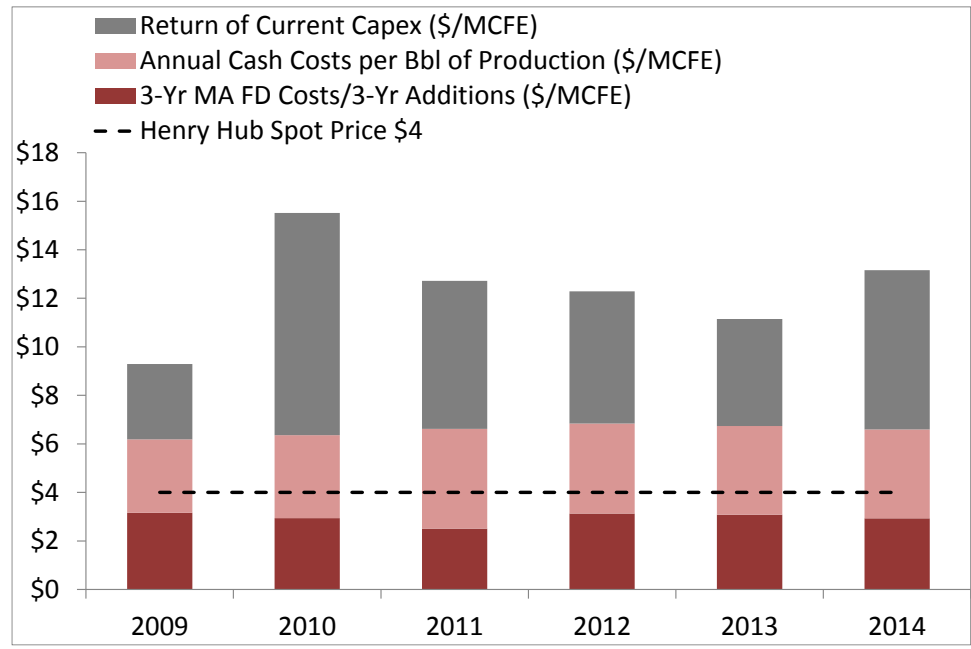
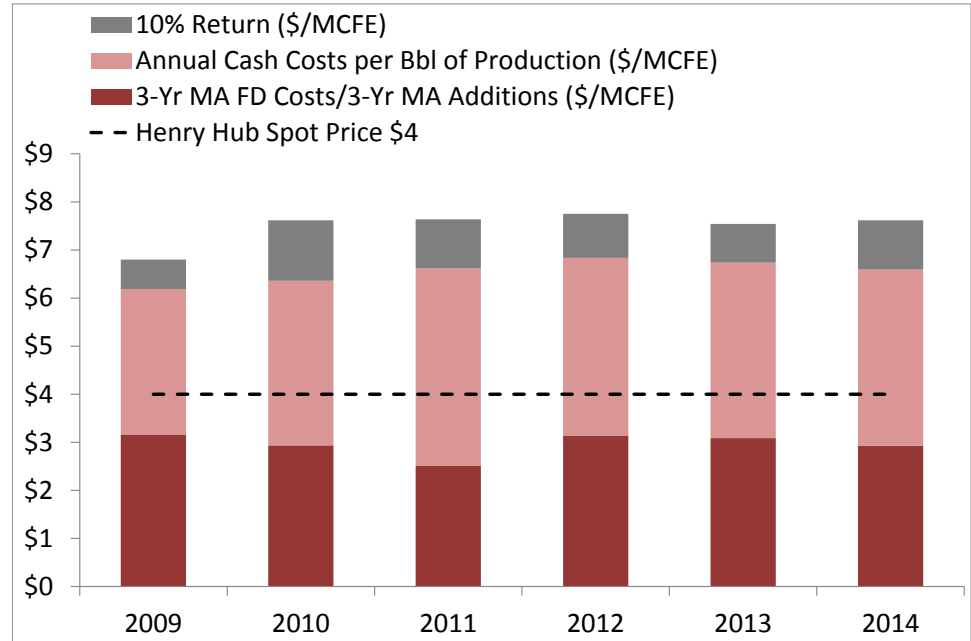


# Implications for Gas

*While the pressure is on from oil prices, the implications for natural gas are more interesting to consider.*

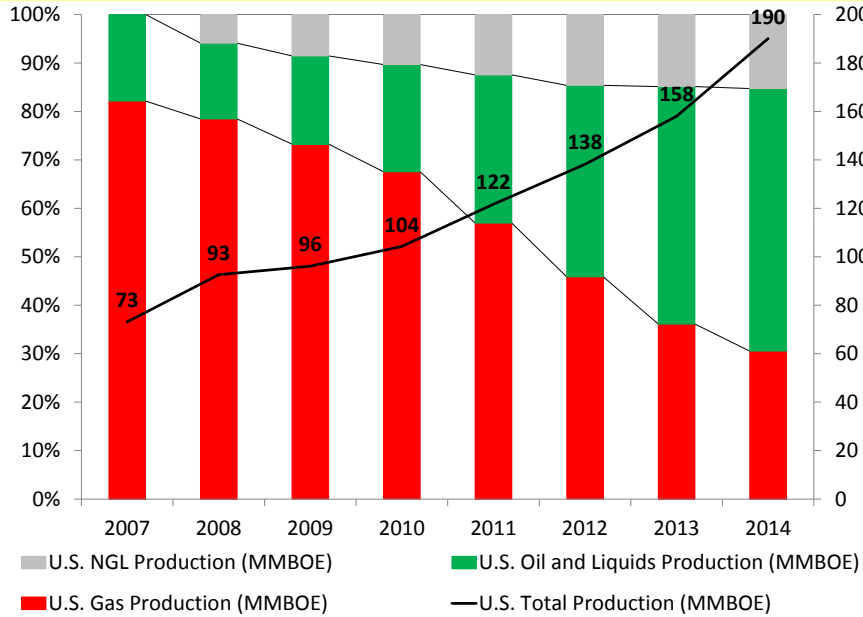
- With a 10 percent return assumed, the minimum back to producers and their investors, **the implied natural gas price is close to \$8 per million Btu (MMBtu)**. However this only returns a portion of current capex. **To return 2014 capex producers would have needed an implied price of more than \$13, on average.**
- Much of the incremental gas supply for the U.S. in recent years has come in association with liquids production or where enough ethane is present and can be captured to justify drilling in nonassociated (dry) gas locations. **Perhaps as much as 50 percent or more of U.S. gas supply is linked to liquids prices.**
- As a result, **oil prices are being watched closely** for hints about gas supply and price impacts.

*Our full report with 2014 data is forthcoming in April 2015.*



# Bonus: It Takes an Industry

**An industry leader with an early shift to liquids**



**A successful gassy player**

